Responses to Comments in Letter 21 from Susan Meyer, Wetland Specialist, Department of Ecology

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Thank you for your comment. Section 3.5.2, Custer-Intalco Transmission Line No. 2, of the Draft EIS acknowledges that if the new transmission line cannot avoid wetlands, wetland delineations would need to be performed before wetland impacts can be quantified and wetland permits can be issued. The Bonneville Record of Decision would include conditions if towers need to be constructed in the right-of-way. These conditions would be that detailed wetland delineations, impact assessments, and mitigation design and monitoring plans will be completed concurrent with the proposed project.

2. Thank you for your comment. As noted in Section 3.4.5 of the Draft EIS, EFSEC has developed appropriate process wastewater and stormwater permits that include both effluent standards and a monitoring schedule for stormwater discharge from the cogeneration facility. Table 3.4-7 of the Draft EIS identifies the effluent limitations.

3. Thank you for your comment. If a recommendation for approval is made to the governor, EFSEC would develop a Section 401 water quality certification that would require submittal of a final Wetland Mitigation Plan for review by EFSEC and its Ecology contractors. In addition to detailed grading and planting plans, the final mitigation plan would include monitoring and contingency plans and all other elements recommended by existing, applicable Ecology guidance.

4. Figure 3.5-2 in Section 3.5, Wetlands, of the Draft EIS is not intended to depict wetlands. It is a map of vegetation types. Reference to wetlands has been removed from this figure. Wetland communities are accurately displayed in Figure 3.5-1 of the Draft EIS.

Responses to Comments in Letter 22 from M. D. Nassichuk, Manager, Pollution Prevention and Assessment, Environment Canada

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Section 3.2.3 of the Draft EIS has been updated to include a discussion of the potential health impacts of $PM_{2.5}$.

2. Section 3.2 of the Draft EIS has been updated to include a more thorough analysis of potential ambient concentrations of particulate matter and $PM_{2.5}$. As noted in Letter 12, Response 1, it was conservatively assumed that all particulate matter emissions were less than 2.5 microns in size.

3. Section 3.2 of the Draft EIS has been updated to include modeling of long range impacts of particulate emissions that include secondary particulate. Long range ambient air quality concentrations were assessed using the CALPUFF model.

4. Section 3.2 of the Draft EIS has been updated to include the impacts of start-up scenarios.

5. In a Settlement Agreement with the Counsel for the Environment, the Applicant has committed to remove the refinery boilers if the cogeneration project is constructed and begins operation.

6. For the review of air emissions in the scope of a permitting decision, state and federal regulations require an assessment of impacts on ambient air quality and rely only on tonnage increases as thresholds for levels of review detail. The annual mass emissions were relied on to determine that Prevention of Significant Deterioration review was applicable, and these emissions were input as applicable into the dispersion models.

   In response to this comment, the percentage increase in the Whatcom County and Lower Fraser Valley airsheds, for which the project would be responsible, was calculated based on the data in the Greater Vancouver Regional District's 2003 Forecast and Backcast of the 200 Emissions Inventory for the Lower Fraser Valley Airshed 1985-2000. The results are shown in the table below.

Annual Mass Emissions

Emissions Source	Pollutant						
	CO	NO_x	VOC	SO_x	PM_{10}	$PM_{2.5}$	NH_3
Whatcom County							
Total metric tons	114,654	17,396	40,283	10,063	1,542	2,536	3,490
Lower Fraser Valley							
Total metric tons	481,933	99,897	111,196	18,769	15,364	8,964	18,003
Sum of both airsheds, metric tons	596,587	117,293	151,479	28,832	16,906	11,500	21,493
BP Cogen/Refinery							
Max emissions, metric tons[1]	143.2	211.8	38.4	46.3	237.5	237.5	157.2
Expected emissions, metric tons[2]	73.7	164.4	25.0	45.0	85.3	85.3	157.2
Refinery reductions, metric tons	-49.0	-453.1	-2.7	-6.4	-9.1	-9.1	0.0
% of Whatcom County Emissions							
Maximum BP Cogen emissions	0.1	1.2	0.1	0.5	15.4	9.4	4.5
Expected BP Cogen Emissions	0.1	0.9	0.1	0.4	5.5	3.4	4.5
BP Refinery reductions	0.0	-2.6	0.0	-0.1	-0.6	-0.4	0
% of Whatcom County and Lower Fraser Valley Airshed Emissions							
Maximum BP Cogen emissions	0.02	0.18	0.03	0.16	1.41	2.07	0.73
Expected BP Cogen emissions	0.01	0.14	0.02	0.16	0.50	0.74	0.73
BP Refinery reductions	-0.01	-0.39	0.00	-0.02	-0.05	-0.08	0.00

1. Maximum emissions used for regulatory purposes.
2. Expected emissions include refinery boiler reductions.

7. See specific responses below.

7(1) The cogeneration project and the refinery boilers are two technologically different processes, constructed and operated for different reasons. The refinery boilers produce steam only for the refinery and are not designed or operated to produce electricity. The technology for heat production in the boilers is notably different the from combustion turbine technology being proposed for the cogeneration project, and it is therefore normal for the two processes to have different levels of emissions. It is beyond the scope of this EIS to evaluate why refinery boiler emissions are different from those of the project.

7(2) The Draft EIS has been updated to indicate that the conversion rates used by the Applicant for the long range impact of fine particulate in the airshed represent the higher end of supportable data. The quoted conversion rates (20% for SO_2 and 33% for NO_x) could be achieved under low dispersion conditions, when the maximum impacts could be expected to occur. In general, low dispersion conditions (i.e., lower wind speeds) are usually associated with higher relative humidities when water is present, resulting in the higher conversion rates.

7(3) The per-ton conversion analysis has been corrected. Mass of converted particulate is calculated based on stochiometry.

7(4) Table 3.2-8 of the Draft EIS has the correct data. Table 3.2-9 has been updated accordingly.

7(5) The footnote in Table 3.2-15 has been revised to indicate the maximum $PM_{2.5}$ emissions.

7(6) Thank you for your comment. The net regional change in PM_{10} emissions has been corrected.

7(7) Thank you for your comment. Table 3.2-23 has been simplified.

7(8) Thank you for your comment. The most recent air quality report (Greater Vancouver Regional District 2003) indicates that recent air quality trends in the Lower Fraser Valley have not changed significantly from data collected in the previous year.

Responses to Comments in Letter 23 from Mary C. Barrett, Senior Assistant Attorney General

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. At this time, the Applicant would be the sole owner and operator of the project. If the project does change ownership, EFSEC would be responsible for reviewing and approving this change. The Applicant is working with TransCanada to develop the project, but there is no official commercial agreement between the two entities. Any new owner of the facility, TransCanada or any another developer, would be required to comply with the Site Certification Agreement.

2. Please refer to Response 1 of this letter.

3. Bonneville does not now intend to purchase power from the BP Cherry Point Cogeneration Project. The power would be available to customers that are connected to the Bonneville system.

4. Please refer to Response 1 of this letter.

5. Regarding the supply of electrical energy, the Western Electricity Coordinating Council (WECC) has concluded that projected reserves are expected to be adequate through 2012, assuming that approximately 32,300 MW of planned new generation will be constructed and sufficient energy will be available for peak demands. The WECC has determined that capacity adequacy may become dependent on Pacific Northwest hydroelectric conditions after 2008.

   Both the WECC and the Northwest Air Pollution Authority (NWPCC) include existing generation, renewables, and conservation in their forecasts.

   The NWPCC's long-term forecast reflects, "estimates of future demand unreduced for conservation savings beyond what would be induced by consumer responses to price changes." (NWPCC 2003, p. 4).

   The Northwest Power Pool comprises all or major portions of the states of Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming; a small portion of Northern California; and the Canadian provinces of British Columbia and Alberta. From 2003 through 2012, peak demand and annual energy requirements are projected to grow at annual compound rates of 1.6% and 1.7%, respectively. With a large percentage of hydro-generation in the region, the ability to meet peak demand is expected to be adequate for the next 10 years. Capacity margins for this winter peaking area range between 23.4% and 29.6% for the next 10 years.

   WECC's 2002-2012 10-year Coordinated Plan Summary updates the load growth forecast for the Northwest Power Pool Area. It states, "for the period from 2003 through

2012, peak demand and annual energy requirements are projected to grow at annual compound rates of 1.6 percent and 1.7 percent, respectively." (WECC 2002, p. 10). Section 1.2.2 of the Draft EIS has been revised to include the more recent estimates. The WECC report projects generation additions in the Northwest Power Pool Area totaling 11,863 MW from 2003 through 2012, including 8,753 MW combined-cycle combustion turbine, 971 MW hydro, 105 MW geothermal, and 87 MW "other." The WECC report does not identify conservation resources.

The U.S. Department of Energy (2004) in its Annual Energy Outlook 2004 with Projections to 2025, referred to as the *AEO2004* report, projects, "continued saturation of electric appliances, installation of more efficient equipment, and the promulgation of efficiency standards are expected to hold growth in electricity sales to an average of 1.8 percent per year between 2002 and 2025." Section 1.2.2 of the Draft EIS has been revised to include the more recent estimate.

The report continues, "changing consumer markets could mitigate the slowing of electricity demand growth seen in the *AEO2004* projections. New electric appliances are introduced frequently. If new uses of electricity are more substantial than expected, they could offset some or all of the projected efficiency gains."

AEO2004 also projects generation capacity additions: "With growing demand after 2010, 356 gigawatts of new generating capacity (including end-use combined heat and power) will be needed by 2025, with about half coming on line between 2016 and 2025. Of the new capacity, nearly 62 percent is projected to be natural-gas-fired combined-cycle, combustion turbine, or distributed generation technology." Regarding renewable generation, *AEO2004* projects, "renewable technologies account for just over 5 percent of expected capacity expansion by 2025—primarily wind and biomass units."

Regarding renewable generation technologies, "*AEO2004* projects significant increases in electricity generation from both wind and geothermal power. From 4.8 gigawatts in 2002, total wind capacity is projected to increase to 8.0 gigawatts in 2010 and 16.0 gigawatts in 2025. Generation from wind capacity is projected to increase from about 11 billion kilowatt-hours in 2002 (0.3 percent of generation) to 53 billion in 2025 (0.9 percent). Nevertheless, the mid-term prospects for wind power are uncertain, depending on future cost and performance, transmission availability, extension of the federal production tax credit after 2003, other incentives, energy security, public interest, and environmental preferences. Geothermal output, all located in the West, is projected to increase from 13 billion kilowatt-hours in 2002 (0.3 percent of generation) to 47 billion in 2025 (0.8 percent).

"Generation from municipal solid waste and landfill gas is projected to increase by nearly 9 billion kilowatt-hours, to about 31 billion kilowatt-hours (0.5 percent of generation) in 2025. No new waste-burning capacity is expected to be added in the forecast. Solar technologies are not expected to make significant contributions to U.S. grid-connected electricity supply through 2025. In total, grid-connected photovoltaic and solar thermal generators together provided about 0.6 billion kilowatt-hours of electricity generation in

2002 (0.02 percent of generation), and they are projected to supply nearly 5 billion kilowatt-hours (0.08 percent) in 2025."

6. The description of the No Action Alternative in Section 1.4 of the Draft EIS indicates that none of the environmental impacts resulting from construction or operation of the project would occur, and this includes no incremental increase in greenhouse gas emissions. Section 3.2.4 of the Draft EIS has been revised to better describe the continued impacts on air quality associated with no action.

7. While Ecology does address water quality impacts through its regulation of the National Pollutant Discharge Elimination System (NPDES) permit for the refinery, EFSEC must also address impacts as part of the NPDES permit for the cogeneration facility. Water quality impacts are discussed in the Draft EIS in Section 3.4, Water Quality, and the effects of those impacts are discussed in Section 3.7, Vegetation, Wildlife, and Fisheries. The cogeneration facility will represent an estimated 8% increase in discharge from the refinery outfall, which is within the variability of existing discharge rates from the refinery. It should also be noted, as discussed in Section 3.4.1 of the Draft EIS, "the refinery uses approximately 50% of the organic and hydraulic capacity of the wastewater treatment system."

   Increases in temperature and salinity have been modeled as insignificant (BP 2002). Kyte (Prefiled Testimony, Exhibits 27.0 and 27R.0) testified that while the dilutions at the Zone of Initial Dilution and the chronic dilution zone required by the refinery's existing NPDES permit were 28:1 and 157:1, respectively, in actuality they have been shown to be 144:1 and 1709:1. Given the low level of biological effect reported at the outfall under present conditions, it is unlikely the cogeneration facility will have any measurable effect on marine life.

   The impact of wastewater discharge from the cogeneration project on state water quality standards was reviewed as part of the State Waste Discharge and NPDES permits developed for the cogeneration project. This review concluded that the discharge would not violate state water quality standards.

8. The Application under review is, and always has been, submitted solely by BP West Coast Products, LLC. If the project is approved, all permits and certifications would be issued to BP West Coast Products, LLC. If BP West Coast Products, LLC decides to sell part or all of the project, that transaction would be subject to review requirements established in EFSEC laws and rules. The Settlement Agreement with the Counsel for the Environment addresses how new ownership of the project would be addressed for mitigation conditions associated with greenhouse gas emissions. The new owner would have to comply with the requirements of the Site Certification Agreement issued to the project.

9. Section 1.8.1 of the Draft EIS has been revised to reflect the impacts of the proposal. The discussion of impacts from global warming in the Pacific Northwest has also been augmented in Section 3.2 of the Final EIS.

10. Section 1.8.2 of the Draft EIS has been revised to reflect that the Applicant is committed to shutting down three refinery boilers if the cogeneration facility is constructed and operated.

11. Ammonia emissions were analyzed per the requirements of Chapter 173-460 WAC. Ammonia emissions are regulated as a toxic air pollutant in Washington State. Ammonia emissions as a result of "slip" were modeled and compared against the appropriate Acceptable Source Impact Level (see Table 3.2-14 of the Final EIS). The ASIL is a level of concern that conservatively protects human health and the environment. Best Available Control Technology for ammonia slip is to control emissions below a specified target level, in this case 5 ppm.

12. The Applicant used the EPA test method for PM_{10} only in estimating the actual emissions that might occur from the project. This estimate of actual emissions was used to assess the likely long range impact on the airshed. The test method was not used for regulatory review of the air emissions or for determining compliance with U.S. or Canadian ambient air quality standards.

13. The discussion in Section 3.2.5 of the Draft EIS has been revised to include specific impacts from global warming that might occur in the Pacific Northwest.

14. As noted in Response 12 of this letter, the corrections to the EPA test method for primary PM_{10} emissions were not used to determine the compliance of the project with the Prevention of Significant Deterioration (PSD) and new source review requirements. The analysis of secondary particulate formation is required to assess the impacts on visibility and haze in federally protected Class I areas. The analysis was based on maximum potential emissions from the cogeneration project and did not include any adjustments for primary particulate test method. Additional modeling (not required by the PSD and new source review programs) was performed to determine the long range impact of particulate emissions; results are shown in Appendix B of this Final EIS. Exhibit 22.2, Page 2 in Appendix B shows the predicted PM_{10} concentrations for potential maximum annual emissions excluding any refinery reductions or test method adjustments. Table 3.2-23 of the Draft EIS has been revised to reflect the impacts on regional particulate matter emissions with and without the test method adjustment.

15. Please refer to Response 7 of this letter. The diffuser was inspected in August 2003. A diffuser inspection was a requirement of the refinery NPDES permit. A video was taken and a report was written and sent to the Department of Ecology.

Responses to Comments in Letter 24 from Ken Cameron, Manager, Policy and Planning, Greater Vancouver Regional District, Canada

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Additional information regarding the health effects of $PM_{2.5}$ has been added to Section 3.2 of the Final EIS.

2. Modeling of long range emissions without refinery reductions or "adjustments" for test methods to assess potential actual emissions has been included in the Final EIS (see Section 3.2). For regulatory purposes, test method and other adjustments were not considered.

3. Please refer to Letter 22, Response 7(2).

4. Section 3.2 of the Final EIS describes additional long range modeling data, which include the Canadian airshed. The modeling includes conversion to secondary particulate. The data presented in the Draft EIS were based on estimates performed with the Industrial Source Complex (ISC) Prime model; it included primary and secondary particulate by adding 20% of the sulfur emissions to the particulate matter emissions. This represented the worst-case scenario. Primary and secondary particulate were also modeled with the CALPUFF model for the annual averaging time (see isopleths in Appendix B of this Final EIS).

5. A discussion of the relationship between ammonia and secondary particulate has been included in Section 3.2 of the Final EIS. Regarding the reporting of maximum predicted ammonia concentrations in Canada, ammonia emissions from the project were reviewed under the requirements of Chapter 173-460 WAC, which considers ammonia to be a toxic air pollutant. The Applicant used a Gaussian dispersion model (ISC Prime) to determine the maximum concentration of this pollutant (reported in Table 3.2-14 of the Final EIS) and found that the resulting concentration was well below the applicable Acceptable Source Impact Level (ASIL). The ISC Prime model is used to assess impacts within a 50-km range of the source. Therefore, maximum modeled ambient concentrations in Canada would also be less than the maximum value reported (2.8 $\mu g/m^3$, 24-hour average).

6. Maximum ambient concentrations resulting from various modes of facility startup are described in Section 3.2 of the Final EIS.

7. Please refer to Letter 22, Response 6.

8. Please refer to Letter 22, Response 5. The Applicant is not seeking credit for refinery emissions reductions for regulatory purposes. Therefore, even though the removal of the refinery boilers will benefit ambient air quality concentrations, that benefit cannot be taken into account; for regulatory purposes, the analysis of environmental impact is based on maximum emissions from the cogeneration project. However, the Applicant has made

certain assumptions regarding what the expected benefit might be and has evaluated the long range impact on resulting ambient air quality. Appendix A in this Final EIS shows isopleths for criteria pollutants, which take into account refinery reductions.

9. The Applicant has demonstrated that particulate matter (PM) emissions, including particulate matter less than 2.5 microns, meet both U.S. and Canadian regulatory standards. The Applicant is using Best Available Control Technology (BACT) to control PM emissions, represented by the combustion of natural gas only in the combustion turbines. Under state and federal laws and regulations, compliance with ambient air quality standards in an attainment area and application of BACT for emission control are considered appropriate mitigation of impacts.

10. Pursuant to an Agreement with the Counsel for the Environment, the Applicant's proposal for greenhouse gas mitigation has been modified and now requires additional measures. As described in Section 3.2 of the Final EIS, the mitigation plan requires formal reporting of offsets that have been achieved and encourages projects in the Whatcom County area.

11. Thank you for your analysis and comment. It should be noted that the adjustments to maximum potential emissions were not considered for regulatory purposes. The intent was to estimate the impacts of actual emissions on the airshed. Please refer also to Letter 23, Responses 12 and 14.

12. Thank you for your comment. It has been conservatively assumed that all PM is emitted as $PM_{2.5}$. Letter 22, Response 6 addresses the percentage of BP's Cherry Point Refinery contribution of emission to the Whatcom County and Fraser Valley airsheds.

13. The particulate matter adjustments were not taken into account for regulatory purposes. The intent was to estimate the impacts of actual emissions on the airshed. Through a Settlement Agreement with the Counsel for the Environment, the Applicant has committed to remove the refinery boilers if the cogeneration project is constructed and operated.

14. Please refer to Letter 22, Response 7(2).

15. Thank you for your comment.

16. Isopleths depicting the impact on ambient air concentrations of particulate matter, averaged over 24 hours, have been added to Appendix B of this Final EIS. These isopleths include a 20% conversion to secondary particulate and do not take into account refinery emissions reductions.

17. The evaluation of impacts on ambient concentrations of ozone are only required when the proposed facility is in an area designated as non-attainment for ozone. In such a case, state and federal regulations consider nitrogen oxides (NO_x) and volatile organic

compound (VOC) emissions as ozone precursors. Whatcom County is in an attainment area for all criteria pollutants, including ozone.

18. Impacts on ambient air quality from startup of the facility have been added to Section 3.2 of the Final EIS.

19. A discussion of the impacts of particulate matter on human health has been added to Section 3.2 of the Final EIS.

20. Please refer to Letter 24, Response 9.

21. Selective catalytic reduction (SCR) has been the technology of choice for controlling NO_x emissions for this type of power generation facility. SCR meets the three BACT criteria that are required under the Prevention of Significant Deterioration (PSD) program: (1) the most stringent form of emissions reduction technology possible will be used; (2) the technology is technically feasible, and (3) the technology is economically justifiable. Although other non-ammonia-based technologies exist (XONON and SCONOx for example), neither of these has been demonstrated as technologically possible for the size of combustion turbine project being proposed. To reduce collateral effects, ammonia emissions will be limited to no more than 5 ppm.

    Regarding the toxic effects of ammonia emissions, EFSEC requires an ambient air quality analysis of toxic air pollutant emissions in accordance with WAC 173-460 Controls for New Sources of Toxic Air Pollutants. The toxic air pollutants are evaluated for both acute (24-hour) and chronic (annual) effects as required by the regulation. The quantities of all toxic air pollutants known to be emitted from the turbines and duct burners, including ammonia, were estimated and screened against the small quantity emission rates in WAC 173-460. Ammonia did not exceed the applicable Ambient Screening Impact Level (ASIL), and therefore no adverse health impacts are expected to occur from the emissions of this pollutant. The maximum ammonia concentration in Canada was determined to be 1.1 $\mu g/m^3$.

22. Please refer to Letter 22, Response 5.

23. Please refer to Letter 24, Response 9. There is no regulatory basis for requiring an offset of emissions in an area that is designated “attainment.” The proponent of the Sumas Energy 2 Project offered to voluntarily offset PM emissions, and EFSEC included this as a requirement in that project’s Site Certification Agreement.

24. Please refer to Letter 24, Response 10.

25. Regarding the emission of particulate matter, although the tons per year emitted represents a large number, the impact on ambient air quality and the environment is not deemed significantly adverse. Emissions of all air pollutants meet both U.S. and Canadian regulatory standards and guidelines. Regarding greenhouse gas emissions, the Applicant has proposed a plan that would mitigate 23% of CO_2 emissions.

26. Thank you for your comment. The table has been revised in the Final EIS.

27. Air Quality Index (AQI) hours data for 2001 have been added to Table 3.2-5 in the Final EIS. In 2002, the Greater Vancouver Regional District discontinued the practice of providing the data in the form presented in Table 3.2-5. In 2001, air quality in the district was measured as "good" 98.4% of the time, with "fair" and "poor" readings occurring 1.6% and less than 0.1% of the time, respectively. These readings are equivalent to or better than conditions recorded during the past few years. During 2001, one air quality advisory was issued. During 2002, air quality was reported as "good" 97.4% of the time, with "fair" and "poor" readings occurring 2.6% and less than 0.1% of the time, respectively. These readings are equivalent to or slightly worse than conditions recorded during the past few years. No air quality advisories were issued in 2002.

28. Table 3.2-8 of the Draft EIS had the correct data. Table 3.2-9 has been updated accordingly.

29. The footnote to Table 3.2-15 has been revised to indicate that the maximum concentrations of $PM_{2.5}$ are equal to the maximum concentrations of PM_{10}. The concentrations for $PM_{2.5}$ in Table 3.2-16 are the maximum concentrations, and the table heading has been revised to reflect this. Table 3.2-20 of the Final EIS has been corrected and reorganized for clarity.

30. Table 3.2-23 of the Final EIS has been revised for clarity. The data have been corrected to reflect molecular weights of compounds.

Responses to Comments in Letter 25 from David M. Grant,
Deputy Prosecuting Attorney, Whatcom County

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Dave Enger, a traffic engineer with Traffic Planning and Engineering Inc., analyzed the intersection of Grandview Road and Vista Road with the proposed Delta Tech Industrial Park, including the proposed closure of the southern segment of Delta Line Road. Based on Mr. Enger's results, if the proposed Delta Tech Industrial Park is open prior to the start of construction of the cogeneration facility and the southern portion of Delta Line Road is closed, the level-of-service (LOS) at the intersection of Grandview Road and Vista Drive would change from C to D. LOS D is acceptable to Whatcom County, and therefore traffic flow through the intersection is considered adequate. For further explanation, refer to Enger, Prefiled Testimony, Exhibit 34R.0.

   Construction traffic will not use Brown Road during construction of the cogeneration facility. With little or no increase in traffic on Brown Road, no impact mitigation is proposed.

2. See specific responses below.

2(1) As stated in Malushte, Prefiled Testimony, Exhibit 32R.0, "identification and acknowledgement of a new fault must meet the rigorous 'standard of care' followed in the USGS process. Review of USGS' most recently published PSHA studies (Reference: USGS Open-File Report 02-467; also, visit http://geohazards.cr.usgs.gov/eq/2002faults/flt-spreadsheet-2002.html for the list of recognized faults and their parameters) shows that Sumas and Vedder Mt. faults have not been recognized by USGS. This is despite the fact that the USGS has been conducting focused research in the Pacific Northwest region; yet, the USGS' current research plans (http://geology.wr.usgs.gov/wgmt/pp02.html and http://www.usgs.gov/contracts/nehrp/attach-a.doc) do not include the hypothetical Sumas and Vedder Mt. faults as potential faults that warrant studies."

2(2) As stated in Malushte, Prefiled Testimony, Exhibit 32R.0, "detailed site-specific geotechnical analyses have already been performed for the Cogeneration site. Other soil information from somewhere in the 'area' will not supersede the data developed in these specific geotechnical investigations because geotechnical properties can vary significantly within a distance of mere few hundred feet, let alone miles. If there is any belief that such data may have some significance in terms of regional seismic activity. I would reiterate that the USGS is the most recognized and accepted source for seismic sources (i.e., faults) and hazards. It is unlikely that information for the petroleum exploration studies will provide any relevant and reliable data to improve the design safety of the BP Cogeneration facility."

2(3) The commenter is correct. The findings of the BP Cherry Point Cogen Project, Report of Subsurface Investigation/Laboratory Testing, URS Corporation, July 3, 2003, will assist in the detailed design of foundations and structures.

2(4) As stated in Malushte, Prefiled Testimony, Exhibit 32R.0, "the USGS has already performed a detailed PSHA. The most recent PSHA for the USGS was just published a few weeks ago, October 29, 2003. It shows that the BP Cogeneration facility site has significantly less seismic hazard potential than the default design ground motion prescribed in UBC-97.…Design per UBC-97 will be completely appropriate and will provide a conservative design for the cogeneration facility."

2(5) As stated in Malushte, Prefiled Testimony, Exhibit 32R.0, "the two sites are approximately 23 miles apart. Soil and seismic hazard conditions can vary significantly over such distances….The likelihood of commonalties of any significance between geology of these sites is thus minimal. Reference to analyses related to an entirely separate and distant site, like Sumas Energy 2 location, would provide no useful information for the Cogeneration plant and is more likely to confuse than clarify understanding of conditions at the BP Cogeneration site."

2(6) The report referenced (URS 2003c) is strictly the raw data from geotechnical field investigations to be used by Bechtel Power Corporation during final design of the project components. In his prefiled testimony, Dr. Sanjeev R. Malushte notes that these data were used in a subsurface investigation and foundation report. He also notes that the site has significantly less seismic hazard potential than the default design in the Uniform Building Code. Finally, he noted that a site-specific PSHA would not be appropriate.

2(7) As stated in Moore, Prefiled Testimony, Exhibit 20.0, "what the Applicant said it is willing to do is conduct a periodic monitoring program similar to the one currently in use at the refinery would be appropriate. Under such a program, various aspects of the facility's structural integrity are checked on a regular basis, and after significant seismic events. Inspections include:

- Inspect major foundation seams for differential movement,
- Inspect major foundation grout pads for cracking,
- Check for proper alignment of major piping shoe supports,
- Check piping spring hangers for proper position,
- Check for piping and cable tray misalignment at building penetrations,
- Review equipment vibration monitoring logs for unusual vibration patterns.

"If problems or discrepancies are identified during the inspections, appropriate repairs will be made. These inspections ensure that structural components would continue to serve their intend function.

"The facility will also have vibration monitors on major pieces of rotating equipment. Were a significant seismic event to occur, the cogeneration facility would likely shut down because vibration monitors would see the tremors as high vibrations and would trip the equipment."

3. Thank you for your comment. See Responses 3(1) through 3(44) that address comments provided by Dr. Stenberg in the attached report.

4. See specific responses below.

4(1) Both noise studies used accepted and approved methods for assessing noise impacts. Noise impacts at 15 receptors, both industrial and residential, within an approximate 1.5-mile radius of the cogeneration facility were monitored during the day and night. Modeling was based on existing noise in the area and anticipated noise from the facility. Perceptible noise increases (3 dBA or greater) were not identified at a single site, including immediately adjacent to the proposed facility. Anne Eissinger reports that the herons in the nearby colony showed no evidence of disturbance either by the existing refinery or the recent construction of a bridge over Terrell Creek within 1,000 feet of the colony.

4(2) Roadside measurements were taken to assess the impact of predicted changes in vehicular traffic patterns, primarily during the construction phase of the project, but also to a lesser extent operational truck noise. The 15-minute time frame is typical of traffic noise measurements taken in accordance with FHWA/WSDOT noise measurement protocols (FHWA 1996, WSDOT 2003).

The time of day these measurements were taken is not important because the purpose of the measurement is to calibrate the traffic noise model by comparing actual noise measurements to modeled results.

The roadside measurements were not intended to provide background noise information. Suitable background levels are available from the Hessler study, the results of which are presented in Table 3.9-5 of the Draft EIS.

4(3) Washington State and most other state and federal agencies that deal with noise issues require the use of A-weighted noise level measurement to assess environmental noise impacts. A-weighting estimates the response of the human ear under conditions that would reasonably be judged normal. C-weighting is most often used for extremely highnoise levels and short-term noise sources, such as pile-driving, but not for industrial facilities similar to the cogeneration facility being considered by the EIS. At Fort Lewis, Washington, the U.S. Army uses C-weighting in artillery-related noise control.

4(4) Washington State environmental noise regulations (WAC 173-60) were observed for this study. The WAC rules apply throughout the state and are considered reasonable and appropriate for this EIS.

The suggested approach would be a “relative” approach to noise limitation, as used by most Departments of Transportation in defining noise levels for new construction that would “substantially exceed” existing levels. Such levels are typically in the 10 to 15 dB range. The WAC 173-60-040 uses an “absolute” approach in defining impacts that is invoked for all projects throughout the state. In any case, as noted in Table 3-9.4 of the

Draft EIS, 3 dB is greater than the noise impact modeled at any receptor. Most noise-related literature regards 3 dB to be at the threshold of perceptible change. The perception of a noise increase is not automatically considered a noise impact.

4(5) Greater sensitivity to nighttime environmental noise is compensated by the noise limitations in WAC 173-60-040, which reduce allowable nighttime noise by 10 dB for all categories of noise receptors, including residential. Eliminating the daytime sound levels from the average would artificially weight the data to a degree not intended by the regulation.

4(6) Sound propagates spherically from a point (stationary) source, dispersing geometrically at a minimum rate of roughly 6 dB for each doubling of distance from the source (without taking into account ground absorption or meteorological interference, which is not consistent throughout the seasons or from one year to the next). A sound measured at 80 dB (very noisy) at a distance of 15 meters would therefore attenuate by more than 36 dB at 1,440 meters to 44 dB, below even nighttime noise limits per the WAC. Noise impacts were modeled for sites much closer to the proposed cogeneration facility than 1,400 meters (see Figure3.9-1 of the Draft EIS), and no perceptible noise impacts were identified (Table 3.9-4 of the Draft EIS).

4(7) A change of 1 dB can be perceived under specific conditions, but most authorities consider that under non-laboratory conditions in a heterogeneous noise environment typical of most residential situations where midrange frequency sounds are dominant 3 to 5 dB is the minimum perceptible change in noise level for people with average hearing ability.

4(8) Please refer to Response 4(3) of this letter. Table 3.9-5 of the Draft EIS shows that low frequency noise would be well below the American National Standards Institute (ANSI) recommended limit of 75 to 80 dBC at all but one location—an industrial site. Evaluation of low frequency noise in the Draft EIS exceeds the requirements of applicable regulation and indicates a level of diligence above the norm.

4(9) Eissinger (Prefiled Testimony, Exhibit 31R.0) notes that there is no apparent impact from existing noise at the refinery on the nearby heron colony and that it is reasonable to use standards for noise impacts on human beings to assess impacts on wildlife.

4(10) Please refer to Response 3(2) of this letter. Also, Ann Eissinger testified that the herons “exhibited no observable response” to a bridge construction site (within 1,000 feet of the colony) or the concurrent construction activity at the refinery. Based on these observations, further analysis is not warranted.

5. The project, as proposed, includes only a compressor station constructed within the fenceline of the refinery. The Applicant separately evaluated the feasibility of constructing a compressor at or near Sumas but determined it would not be economically practical and therefore is not part of the proposed project.

6. Please refer to Response 5 of this letter.

7. The project includes “end-of-line” compression inside the refinery fenceline. This compressor would also be within the Heavy Impact Industrial zone of Whatcom County. Please refer to Response 5 of this letter.

8. Thank you for your comment.

<u>Attached Report</u>

3(1) Thank you for your comment. USFWS does not identify great blue heron as a species of concern, candidate, or proposed species for listing. Whatcom County, however, identifies it as a species of local concern. The term “critical habitat” is applied in reference to Endangered Species Act–related species. Critical habitat has not been scientifically defined for great blue heron. Quality habitat associated with great blue heron staging and foraging activities, such as Drayton Harbor, Birch Bay, and Lummi Bay, is located within a 4-mile radius of the Birch Bay great blue heron colony. As described in Section 3.7.1 of the Draft EIS, however, the dominant presence of non-native, invasive plant species associated with the project site (reed canarygrass), including wetland mitigation sites, do not provide habitat conditions typically identified as quality habitat for great blue heron. Reed canarygrass is not generally considered to be a quality foraging habitat for great blue herons because of its height during the growing season and thick matted nature when down in the winter. In addition, long term monitoring of the Birch Bay great blue heron colony has not documented great blue heron staging or foraging activity at the project site or project wetland mitigation areas. Great blue heron habitat and potential project-related impacts on great blue heron are thoroughly addressed in Eissinger, Prefiled Testimony, Exhibit 31R.0.

Mitigation sites located west of the project wetland mitigation sites, as described in the Brown Road Materials Storage Area Final Mitigation Plan (URS 2003a) and Habitat Management Plan (URS 2003b), do not provide habitat conditions typically identified as quality foraging and staging habitat for great blue heron.

As described in Section 3.7.2 of the Draft EIS, treated wastewater associated with the BP refinery’s National Pollutant Discharge Elimination System (NPDES) permitted outfall is not likely to significantly affect Puget Sound habitat that supports a variety of aquatic species such as salmon, other fish, shellfish, and other marine wildlife. Great blue heron foraging habitat associated with the marine environment of Drayton Harbor, Birch Bay, and Lummi Bay is located more than 2.5 miles from the project outfall. Michael Kyte, in Prefiled Testimony Exhibits 27.0 and 27R.0, addresses impacts on marine water quality issues, including toxin bioaccumulation and/or heavy metals.

3(2) Potential impacts on wildlife associated with noise are discussed in Section 3.7.2 of the Draft EIS. As discussed in Section 3.9, Noise, the project meets state standards for noise, and modeling shows that noise associated with the project would result in a 1 dBA increase over existing background noise at most receptor locations. It should also be noted the refinery has been in operation for over 30 years and the herons have continued to occupy the rookery. Whatcom County has approved two residential developments within 1 mile of the Birch Bay great blue heron rookery: a 66-lot residential development located less than a mile northeast of the rookery and a 125-lot residential development located about a half mile northeast of the rookery. Ann M. Eissinger, in Prefiled Testimony Exhibit 31R.0, addresses potential noise impacts on great blue heron.

Under Section 3.7.2 Impacts of the Proposed Action, Construction, Wildlife and Habitat, the following text will be added to the Final EIS: "The Birch Bay great blue heron rookery is located about 1.5 miles from the project site. WDFW management recommendations (2004a) for great blue heron include a 3,280-foot buffer between heron colonies and construction activities." A cooperative agreement between the Applicant and Whatcom County has been completed that addresses noise impacts associated with wildlife.

3(3) Please refer to Response 3(2) of this letter. In addition, as discussed in Eissinger, Prefiled Testimony, Exhibit 31R.0, scientific literature lacks sound-tolerance levels or guidelines to accurately asses impacts on wildlife from noise. Reliance on human levels of tolerance and perceptibility is generally accepted as the best available measure. Potential levels of noise reaching the heron colony and areas of primary use are so low that impact on the herons is unlikely.

3(4) Please refer to Responses 3(2) and 3(3) of this letter. As discussed in Section 3.9, Noise, noise associated with the proposed project would not result in a perceptible increase over ambient background noise. Because maximum noise levels were evaluated, any variation in noise from the project would be a decrease and would not be audibly perceptible.

3(5) Please refer to Responses 3(2), 3(3), and 3(4) of this letter.

3(6) Please refer to Responses 3(2), 3(3), and 3(4) of this letter.

3(7) Please refer to Responses 3(2), 3(3), and 3(4) of this letter.

3(8) As noted in Response 3(2) of this letter, the heron colony is about 1.5 miles from the proposed cogeneration facility. Two of the three noise receptors in the vicinity (south and east of the colony) showed no increase in modeled noise, whereas a third (to the west) showed measurable but not perceptible noise increases. Please refer also to Responses 3(3) and 3(4) of this letter.

3(9) Please refer to Response 3(1) of this letter.

3(10) Construction noise impacts on wildlife are addressed in Section 3.9.2 of the Draft EIS, where it is acknowledged some wildlife may be disturbed during the two-year construction period. In addition, please refer to Responses 3(2), 3(3), and 3(4) of this letter.

3(11) The Draft EIS notes an imperceptible change in noise (0 to 1 dBA at all but one of 15 receptors) relative to existing conditions. In addition, please refer to Responses 3(1), 3(2), 3(3), and 3(4) of this letter.

3(12) Outdoor lighting would generally provide operator access and safety. Lighting off the ground on outdoor equipment would only be required at monitoring platforms. As noted in Section 3.7 of the Draft EIS, exhaust stacks would not be lighted. Because of its location adjacent to the much larger refinery, the cogeneration facility's incremental increase in lighting is expected to be insignificant.

3(13) The commenter is correct that navigation lights will not be necessary on the cogeneration exhaust stacks. Lighting that would be included in the design of the cogeneration facility would enhance safe working conditions. In addition, structures would be painted gray to decrease glare from lights at night and sunlight during the day. Proposed landscaping with trees to the east and north of the cogeneration facility would further reduce the effect of light and glare.

3(14) Please refer to Response 3(13) of this letter.

3(15) Please refer to Letter 23, Response 7, and Response 9 of this letter. Kyte (Prefiled Testimony, Exhibits 27.0 and 27R.0) in his prefiled testimony states, "the Refinery has had no measurable adverse impact on marine water quality during its 30-year history. It is unlikely that the addition of wastewater from the Cogeneration plant, including trace metals, will have an adverse effect during its 30-year projected life." Kyte further states that he has seen no evidence for, "any negative impact to fish or their food sources from the Refinery outfall. The addition of the wastewater effluent from the Cogeneration project should have no additional impact."

3(16) Table 3.4-5 of the Draft EIS shows that refinery wastewater after addition of the cogeneration facility water would be 82.7°F. As presented in the Fact Sheet for the State Waste Discharge Permit, a temperature analysis was conducted of the combined (refinery and cogeneration facility) discharge. The results of the analysis indicated the temperature loading from the cogeneration facility was negligible and in fact the cogeneration wastewater would probably be lower than the refinery process wastewater and the combined discharge would be within water quality standards. The State Water Quality Standards are designed to protect biota in the receiving waters around the refinery outfall.

3(17) Please refer to Letter 23, Response 7.

3(18) Thank you for your comment.

3(19) Please refer to Response 3(15) of this letter.

3(20) Please refer to Response 3(15) of this letter.

3(21) Please refer to Responses 3(15) and 3(16) of this letter.

3(22) Please refer to Letter 17, Response 23. The stormwater collection and treatment system for the cogeneration facility is described in detail in Section 3.4.2 of the Draft EIS. Stormwater would be treated at the cogeneration facility site prior to being discharged to the wetland areas north of Grandview Road. All stormwater discharged to the wetland mitigation areas is expected to meet water quality standards.

3(23) Section 2.2.2 of the Draft EIS states that the stormwater facilities would be designed consistent with Whatcom County and Department of Ecology requirements, including the Stormwater Management Manual for Western Washington (Ecology 2000).

3(24) Section 2.2.2 of the Draft EIS states the cogeneration facility would occupy approximately 33 acres. This would be mostly impervious surface and would be subject to stormwater design constraints. Please refer to Response 3(23) of this letter.

3(25) Thank you for your comment. As stated in David Every's prefiled testimony, Exhibit 28R.0, "it is true that bullfrogs are known to find and reproduce in stormwater ponds. However, that can be prevented by making sure that the ponds go dry during the dry summer or fall months. Salamanders and other amphibians in the area have shorter life cycles and can complete metamorphosis to the land stage in a few months. If the ponds are designed to allow both entry and exit by the amphibians, then they need not become mortality sinks. However, only species that find the other conditions suitable for reproduction are likely to be present. Some species require certain structural features, such as redds, to deposit their eggs. If those features are not present, the species will not breed there. The ponds will be designed and managed to avoid the problems noted."

3(26) The Draft EIS notes the net benefit is a result of 110 acres of habitat creation and restoration that would occur as compensation for the loss of 30.5 acres of generally low quality wetland habitat.

3(27) Thank you for your comment. Grading will be minimized purposely to limit impacts resulting from earth disturbances. Permanent ponds will be avoided to prevent creating bullfrog habitat.

3(28) The revised mitigation plan addresses herons. According to David Every (pers. comm., 2004), no permanent pond was created. The ponds that were created go dry by late summer and do not support bullfrog reproduction. The cogeneration project mitigation will be governed by a 10-year monitoring requirement with the initial as-built report and each annual report delivered to the Corps of Engineers, the Department of Ecology, and Whatcom County for review.

3(29) According to David Every (pers. comm., 2004), the pond created for waterfowl habitat was unfortunately created with steep slopes on the islands. The banks did not erode to their current configuration but have been stable. While water level fluctuation does occur, it does not cause erosion in the ponds, and the level of the ponds does not fluctuate excessively. The driving principle for the hydrologic restoration for this project was to plug ditches and spread water out over broad areas. Water will be directed to CMA2 to get it back to historical pathways that have been disrupted by roads and ditches, but that water will also be spread widely. Detailed hydrologic monitoring is being required as part of mitigation, and it will allow and guide adaptive management as necessary.

3(30) Monitoring heron use of the habitat is being conducted for a year. The results will provide data on both areas and patterns of usage as well as timing. The information will be used to establish the timing of mitigation actions as needed to be sensitive to established heron needs. Please refer also to Response 3(1) of this letter.

3(31) The results of the monitoring mentioned above will be used to adjust activities to the appropriate season. Any tilling will be started early enough to displace nesting activities of ground-nesting birds rather than disrupt established nests.

3(32) The mitigation plan will establish additional forest that could become attractive to herons in the future. The mitigation plan specifically states what measures are included to make remaining habitats more attractive to herons. Please refer also to Response 3(1) of this letter.

3(33) The intent is to use materials available at the site as much as possible. The initial benefit of the habitat features is likely to be most important. As the plantings develop, structural diversity of habitat will improve. In addition, even decomposing woody debris provides some additional habitat value (Every, pers. comm., 2004).

3(34) As noted in the mitigation plan, the artificial snags with cross beams are intended for perching; herons perch on higher vegetation but hunt from the ground. Again, the intent is to provide habitat structure in the short term before the planted trees grow large enough to provide the structure (Every, pers. comm., 2004).

3(35) The intent is to use rooted vegetation, such as rushes, sedges, and grasses, to provide amphibian egg deposition sites. Some experiments in King County, Washington, demonstrated that the function could be provided by artificial structure, but that is not what is proposed here (Every, pers. comm., 2004).

3(36) The brush shelters are proposed for open areas where additional vole production would help herons, not for areas where woody plantings might be affected by voles.

3(37) Thermal benefits, while likely, are probably of minor consequence in coastal Whatcom County where there are few mountains to influence temperature or limit dispersal of wildlife (Every, pers. comm., 2004).

3(38) Benefits come from structural diversity increases, forested connections to the Terrell Creek corridor, and reduction of invasive species, in addition to increases in plant diversity. The proximity of the restoration and compensatory mitigation areas to the active refinery places them in a noise and light impact situation similar to what will result after the cogeneration facility is built; the incremental impact on wildlife use will be small. The functions of the impact areas as wildlife habitat are already degraded because of past activity, including agricultural activity and the building of roads and ditches. The temporal loss will therefore be small and will be compensated by the mitigation measures (Every, pers. comm., 2004).

3(39) Thank you for your comment. Species lists are not a good indicator of impacts. Discussion of effects on habitat is much more important (Every, pers. comm., 2004).

3(40) Thank you for your comment. As described in Section 3.7.1 of the Draft EIS and in Response 3(1) of this letter, the project site and wetland mitigation sites do not provide habitat conditions typically identified as quality foraging or staging habitat for great blue heron. In addition, monitoring of the Birch Bay great blue heron colony has not documented great blue heron staging or foraging activity at the project site or wetland mitigation areas (Eissinger, Prefiled Testimony, Exhibit 31R.0).

3(41) Species of local importance are now addressed in the mitigation plan. Increasing the shrub and forest cover in the Compensatory Mitigation Areas (CMAs) will benefit neotropical migrants in general by providing more suitable habitat. According to the Washington Department of Fish and Wildlife (WDFW) Priority Habitat and Species database, four eagles' nests are located within 2 to 4 miles of the proposed project. Loons have been reported at Lake Terrell about 2 miles away. Pileated woodpeckers could be found along Terrell Creek. Although they could fly over the project site, none of these species or others on Whatcom County's list of species of local significance is likely to use habitats present on the site.

3(42) According to WDFW (2004b), coho salmon, cutthroat trout, and largemouth bass have been documented in Terrell Creek, as noted in Section 3.7.1 of the Draft EIS. WDFW, however, have not documented Puget Sound chinook salmon use of Terrell Creek. NOAA Fisheries and the USFWS have issued their concurrence that the project is not likely to adversely affect any threatened or endangered wildlife or fish species. Concurrence letters from NOAA Fisheries and the USFWS have been added to the Final EIS in Appendix B of this Final EIS.

3(43) As discussed in Response 3(1) of this letter and by Eissinger, Prefiled Testimony, Exhibit 31R.0, the project site and wetland mitigation sites do not provide habitat conditions typically identified as quality foraging or staging habitat for great blue heron. Mitigation sites located west of the project wetland mitigation sites, as described in the Brown Road Materials Storage Area Final Mitigation Plan (URS 2003a) and Habitat Management Plan (URS 2003b), do not provide habitat conditions typically identified as quality habitat for native wildlife species (great blue heron). Proposed wetland mitigation designs for these projects, including planting native tree and shrub vegetation, would improve overall habitat conditions for native wildlife species.

BP has agreed to fund the development of a comprehensive management plan for its land holdings north of Grandview Road. The plan, which will be developed by Western Washington University, will guide and coordinate future actions in the area.

3(44) Thank you for your comment. Please refer to the biological evaluation and the wetland mitigation plan. The mitigation plan and its supporting documents describe how the mitigation sequence has been followed (Every, pers. comm., 2004).

Response to Comment in Letter 26 from Steve and Helene Irving, Ferndale Residents

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. The project would meet all state and federal standards for air quality. In addition, there would be a reduction in air emissions due to shutting down older utility boilers. The water reuse project being developed jointly with Alcoa Intalco Works, Whatcom PUD, and the Applicant, on average, would provide more "reuse" water than the cogeneration facility would use thereby reducing the amount of water normally withdrawn from the Nooksack River.

   Regarding constructing a smaller facility and/or purchasing power from Sumas Energy 1 and Sumas Energy 2 generation facilities, please refer to General Response A.

Response to Comment in Letter 27 from Judith Leckrone Lee, Manager, Geographic Implementation Unit, US EPA

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. The revised Alternatives Analysis (see Appendix A in the Final EIS) provides more detail on the siting of the proposed cogeneration facility to limit wetland impacts.

2. The proposed wetland mitigation plan has been developed in consultation with the Corps of Engineers, Washington Department of Ecology, Washington Department of Fish and Wildlife, and Whatcom County. Wetland functions for both the project site and the wetland mitigation areas were rated using the Methods for Assessing Wetland Functions (Ecology 1999), which is based on the Hydrogeomorphic Approach for Assessing Wetland Functions. Based on this functional assessment, the wetland mitigation area provides an increase in functions and values to fully mitigate wetland impacts of the proposed project.

3. Please refer to Response 2 of this letter.

4. Bonneville has asked officials with the Lummi Tribe whether they have any remaining concerns about the project; they expressed no need for further consultation with Bonneville.

Responses to Comments in Letter 28 from Cathy Cleveland, Blaine Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. Existing water quality and potential impacts are discussed in Section 3.4 Water Quality rather than Section 3.3 Water Resources of the Draft and Final EISs. Table 3.4-5 of the Draft EIS indicates that the existing flow of wastewater to the Strait of Georgia is 2,338 gallons per minute (gpm) and that the cogeneration facility would add an additional 190 gpm. Assuming the facility operates 24 hours a day, the daily discharge added to what is currently being discharged by the refinery would be 273,600 gallons. As discussed in Letter 25, Response 3(15), there would be no discernable difference between the quality of the discharge water and that of the background water quality when measured at the boundary of the permitted mixing zone. This would include salinity and temperature, as well as other characteristics.

2. Thank you for your comment. The decline in the herring population off Cherry Point has been added to the Final EIS. Kyte (Prefiled Testimony, Exhibits 27 and 27R.0) notes no evidence of adverse effect on the fish populations off Cherry Point from the existing wastewater discharge. He also anticipates no adverse effect from the additional discharge from the cogeneration facility. Please refer also to Letter 25, Response 3(15).

3. Thank you for your comment. The great blue heron rookery located about a mile from the project site is discussed in Section 3.7.1, Existing Conditions, State Priority Species, of the Draft EIS.

   As described in Section 3.7.2, Impacts of the Proposed Action, in the Draft EIS, treated wastewater associated with the National Pollutant Discharge Elimination System (NPDES) permitted outfall is not likely to significantly affect Puget Sound habitat that supports a variety of aquatic species such as salmon, other fish, shellfish, and other marine wildlife. NOAA Fisheries and the USFWS have issued their concurrence that the project is not likely to adversely affect any threatened or endangered wildlife or fish species. Concurrence letters from NOAA Fisheries and the USFWS have been added to the Final EIS in Appendix D of this Final EIS.

4. Please refer to Response 2 of this letter.

5. Thank you for your comment. Washington Department of Natural Resources (DNR) is developing a master plan for the Cherry Point Aquatic Reserve; when it is completed, DNR will prepare an EIS.

6. Thank you for your comment.

7. The project has been designed to minimize the emissions of particulate, both as criteria pollutants and as toxic air pollutants. The U.S. Environmental Protection Agency has identified five types of atmospheric pollutants that can contribute to marine deposition:

nitrogen compounds, mercury, other metals, pesticides, and emissions (excluding nitrogen compounds) associated with the incineration of wastes. Emissions of nitrogen compounds will be minimized through the use of Best Available Control Technology (BACT) for both nitrogen oxides (NO_x) and ammonia emissions. The deposition of mercury and other metals from combustion processes are associated with the combustion of dirtier fuels such as coal and fuel oil. The natural gas fuel used for the project is very clean and will not contribute significant amounts of mercury or other metals to the airshed. The project air emissions will not be a source of any types of pesticide. Finally, the project will not combust wastes and will not be a significant source of polycyclic aromatic hydrocarbons (PAHs) or other persistent biocumulative toxins. Because of the clean type of fuel being used by the project and the additional emission controls, the project is not expected to contribute pollutants to local marine waters.

8. Please refer to Response 7 of this letter.

9. Please refer to Response 7 of this letter.

10. Please refer to all responses to Letter 12 for concerns raised by Mr. Cleveland.

11. Thank you for your comment. Section 3.2 of the Final EIS includes a discussion on the health impacts of $PM_{2.5}$.

12. Through the Prevention of Significant Deterioration (PSD) program, emission controls proposed by the Applicant undergo strict scrutiny. Only BACT technology is ultimately permitted. BACT technology must meet three important criteria: technical and commercial feasibility, cost efficiency per ton of pollutant removed, and most efficient removal rate of the pollutant of concern. The commenter suggests the use of the following emission control technologies: gravitational settling, centrifugal separators, wet scrubbers, baghouse filters, and electrostatic precipitators (ESPs). The large volume and dilute nature of the emissions from the combustion turbines render all of these techniques inappropriate for cost and pollutant removal efficiency reasons. Gravitational settling and centrifugal separators are only applicable to large particulate matter such as fly ash, which would not be generated by a combustion turbine facility burning natural gas. These technologies would not be appropriate for high volumes of exhaust that contain a low concentration of particulate, such as the emission from the project. Wet scrubbers, baghouse filters, and ESPs are not cost efficient for the treatment of large volume and dilute emissions of fine particulate. The nature of the particulate also does not lend itself to ESP control. For ESPs, which operate on the principle of charge migration, the low particulate concentration would prevent significant charge buildup on particles, resulting in low migration of particles to the collecting plates. For these turbines, the peak particulate emission concentration is 0.001 to 0.003 grains per standard cubic foot (gr/scf) during natural gas firing, which approaches concentrations that ESP and baghouse vendors are striving to achieve for particulate control in other applications (such as oil-fired or other fossil-fuel fired boilers). The use of an ESP and/or baghouse filter is considered technically infeasible and not representative of BACT. The most stringent "front-end" particulate control method demonstrated for combustion turbines is the use of

low-ash fuel and/or low-sulfur fuel such as natural gas and controlled combustion to minimize particulate formation.

13. Thank you for your comment. The referenced sentence in Section 3.10.1 (Existing Land Use, Project Site and Surrounding Area) of the Draft EIS has been revised as follows: "Northwest of the refinery, residential properties occur in the bayfront community of Birch Bay. According to U.S. Census data in 2000, the Birch Bay Census Designated Place supported a total of 5,105 total housing units with a corresponding population of 4,961. Of the total number of housing units, approximately one-half or 2,620 units were classified as seasonal or occasional use units (Whatcom County 2003a)."

14. Through state law, the Legislature mandates that EFSEC review the impacts of large energy facilities under its jurisdiction, such as this project. State law also requires that EFSEC be the lead agency under the State Environmental Policy Act (SEPA). EFSEC prepares the Environmental Impact Statement pursuant to SEPA law and regulations, which apply equally to all state and local governments in Washington State. EFSEC law also requires that a third party independent consultant be retained to prepare the EIS. Finally, EFSEC contracts with other state agencies to review other permits that may be required by state law or regulation. In formulating its recommendation to the governor, EFSEC must balance the increasing demands for energy facility location and operation in conjunction with the broad interests of the public, which include public health and welfare, and protection of the environment. The governor will make the final decision.

    The Bonneville Power Administration proposes to interconnect the project with the federal transmission system and is the lead federal agency for purposes of the National Environmental Policy Act of 1969 (NEPA). Bonneville's administrator is officially responsible for the EIS as specifically required by NEPA and implementing regulations.

15. Thank you for your comments regarding the odor emissions from the refinery reported by local property owners. The cogeneration project will not be powered by crude or refined petroleum products. Clean natural gas will be burned in the combustion turbines. Sulfur concentrations in the natural gas fuel are extremely low compared with concentrations in oil received from Alaska. Furthermore, combustion of natural gas in the turbines does not emit odors comparable to oil refining processes at the existing refinery. The cogeneration project would therefore not contribute to existing odor problems experienced by local residents.

16. Please refer to Response 15 of this letter.

17. The commenter is correct that the U.S. EPA has established ambient air quality standards for $PM_{2.5}$. However, thresholds to measure impacts of $PM_{2.5}$ under the PSD program have not been established yet. Furthermore, Washington State and the U.S EPA have only recently begun to designate attainment, nonattainment, and unclassifiable areas for $PM_{2.5}$. Table 3.2-11 of the Final EIS indicates ambient concentrations of $PM_{2.5}$ resulting from the project, when added to background levels, do not violate the standards adopted by EPA. Please refer to Letter 12, Response 2 for an analysis of $PM_{2.5}$ emissions compliance

under PSD. Finally, as stated in both the Draft and Final EISs, $PM_{2.5}$ emissions were conservatively estimated as equal to PM_{10} emissions.

18. The cogeneration facility is considered a major source and is therefore required to undergo PSD review because emissions of one or more criteria pollutants exceed 100 tons per year (tpy). The annual emissions from the cogeneration project are shown in Table 3.2-7 of the Final EIS. The 100 tpy threshold for PSD review was exceeded for the following pollutants: NO_x by 133.3 tpy; CO by 57.7 tpy; PM_{10} and $PM_{2.5}$ by 161.6 tpy. It should be noted, however, that to require further analysis under the PSD program, source emissions must only exceed the 100 tpy thresholds, no matter by how much.

    The statement regarding the regulation of $PM_{2.5}$ under the PSD program has been corrected in the Final EIS. It has been determined that $PM_{2.5}$ emissions do not violate state or national ambient air quality standards.

    The mitigation measures proposed by the Applicant (i.e., the emissions control technologies) have been selected based on their compliance with Best Available Control Technology, as mandated by the PSD program. The selected control technologies all represent the highest level of emissions control commercially available for the pollutants in question. These technologies are: selective catalytic reduction for NO_x, an oxidation catalyst for volatile organic compounds and carbon monoxide, and the use of clean natural gas fuel and best combustion practices for particulate matter and sulfur oxide emissions. Regulatory compliance for air emission will be established through a Prevention of Significant Deterioration/Notice of Construction (PSD/NOC) permit that would be issued if the governor approves the project. Permit noncompliance for any and all regulated pollutants would be addressed through appropriate enforcement mechanisms and financial penalties as required by state and federal law and regulations.

19. The Applicant has demonstrated that all regulated air pollutant emissions including both criteria and toxic pollutants from the cogeneration facility will not violate ambient air quality standards. Ambient air quality standards have been established to conservatively protect the health of the population. State and federal regulations do not require baseline monitoring of people's health if a project has demonstrated compliance with applicable standards and thresholds.

20. Both the state and national ambient air quality standards (for criteria pollutants) and the Acceptable Source Impact Levels (ASILs) (for toxic pollutants regulated under state law) conservatively protect human health. The ASILs do not represent a threat to human health, but a level of concern that requires additional modeling to assess whether a threat to human health could exist. Emissions that do not exceed the ASILs are considered below the level of regulatory concern and do not require additional analyses, including the evaluation of synergistic effects. The clean natural gas fuel that will be used by this project would further limit the emissions of toxic pollutants.

21. Please refer to Response 20 of this letter.

22. Please refer to Response 20 of this letter.

23. The proposed project must be located adjacent to the steam host, the BP Cherry Point Refinery. The proposed project would deliver about 510,000 lbs/hr, 750°F, 600 psig steam to the refinery. This steam line must necessarily be as short as possible to minimize heat loss. For a discussion regarding alternative siting of the proposed project and project size, please refer to General Response A.

Responses to Comments in Letter 29 from Kathy Berg, Birch Bay Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. The Applicant has performed extensive modeling of the impacts of air emissions from the proposed project. The modeling was performed to satisfy the requirements of the Federal Prevention of Significant Deterioration (PSD) program and the State of Washington's new source review program. In addition, federal land managers (Forest Service and National Park Service) were consulted regarding impacts on Class I areas that are federally protected. All of the modeling was reviewed for EFSEC by the Department of Ecology and had to meet strict regulatory requirements and guidelines. Emissions of all regulated pollutants, including particulate matter, have been shown to be well below any applicable protective thresholds, and they do not violate national or state ambient air quality standards. Ambient air quality standards conservatively protect the environment and human health.

   As indicated in Section 3.2 of the Final EIS, the Applicant went beyond federal requirements to also analyze the impacts of the emissions in Canada, including impacts on the Fraser Valley. If considered alone, the particulate emissions from the project are well within any Canadian regulatory standards and objectives. In addition, the Applicant has committed to remove three existing boilers at the BP Cherry Point Refinery should the cogeneration project proceed to construction. Removal of these boilers will decrease the overall impact of the project's particulate emissions in both Whatcom County and Canada.

   If approved by the governor, the project would be subject to the conditions of a Prevention of Significant Deterioration/Notice of Construction (PSD/NOC) air emissions permit, which would require monitoring of all emissions and reporting of results to EFSEC and Environmental Protection Agency. If permit conditions are exceeded and it is deemed that an immediate risk to public health may be involved, EFSEC has the authority to stop project operations until the problems are resolved.

2. The project would meet the state and county noise standards. In addition, noise modeling shows that the cogeneration facility is not likely to be heard above existing background (refinery) noise. Three background noise surveys have been conducted around the project site, including the Birch Bay area and Birch Bay Village. One of these surveys was conducted along with a representative of the Whatcom County Planning and Development Services, Jim Thompson. The engineering and construction contractor has guaranteed the Applicant that noise levels would be consistent with the Application for Site Certification. Pre- and post-construction monitoring would be conducted as part of performance testing.

Responses to Comments in Letter 30 from Tom Pratum, Bellingham Resident

Note: The responses listed below are numbered to correspond with the numbers shown in the right-hand margin of the preceding comment letter.

1. A shutdown of the Alcoa Intalco Works would have no practical effect on PUD water diversions from the Nooksack River. If operations at the Intalco facility were suspended or shut down, water would be transmitted directly to the cogeneration facility instead of being transmitted through the Alcoa Intalco Works cooling system. In fact, because the average amount of water required for the cogeneration facility is less than the approximately 4 million gallons per day historically used by Intalco and the extra, reused water would be used by the refinery, the amount of water taken from Nooksack River would be reduced (Anderson, Prefiled Testimony, Exhibit 25.0).

2. Potential temperature increases are addressed in Letter 25, Response 3(16). The final, combined effluent from the refinery and cogeneration facility will be well below permitted limitations as discussed in Letter 23, Response 7.

3. Please refer to Letter 25, Response 3(2).